UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark one)

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended **September 30, 2004**

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ________ to _________

Commission file number **1-8246**

SOUTHWESTERN ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Arkansas	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2350 N. Sam Houston Pkwy. E., Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

(281) 618-4700
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year; if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes: X No: ___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes: X No: ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding at October 25, 2004
Common Stock, Par Value $0.10	36,245,534

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended September 30, 2004	For the three months ended September 30, 2003	For the nine months ended September 30, 2004	For the nine months ended September 30, 2003
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 82,637	$ 52,994	$ 257,494	$ 179,987
Gas marketing	17,989	10,113	42,849	34,386
Oil sales	5,118	3,582	13,460	10,862
Gas transportation and other	5,651	4,379	13,809	10,975
	111,395	71,068	327,612	236,210
Operating Costs and Expenses:				
Gas purchases - utility	4,523	3,496	39,573	32,743
Gas purchases - marketing	16,964	9,025	39,599	31,433
Operating expenses	11,070	9,949	31,280	28,243
General and administrative expenses	9,151	7,937	25,425	23,483
Depreciation, depletion and amortization	19,960	14,896	52,577	40,965
Taxes, other than income taxes	4,290	3,058	12,168	9,016
	65,958	48,361	200,622	165,883
Operating Income	45,437	22,707	126,990	70,327
Interest Expense:				
Interest on long-term debt	4,626	4,324	13,423	13,326
Other interest charges	300	350	1,128	1,072
Interest capitalized	(714)	(457)	(2,007)	(1,323)
	4,212	4,217	12,544	13,075
Other Income (Expense)	(543)	(476)	(1,090)	883
Income Before Income Taxes, Minority Interest & Accounting Change	40,682	18,014	113,356	58,135
Minority Interest in Partnership	(366)	(469)	(1,196)	(1,843)
Income Before Income Taxes & Accounting Change	40,316	17,545	112,160	56,292
Provision for Income Taxes - Deferred	14,917	6,667	41,499	21,391
Income Before Accounting Change	25,399	10,878	70,661	34,901
Cumulative Effect of Adoption of Accounting Principle	-	-	-	(855)
Net Income	$ 25,399	$ 10,878	$ 70,661	$ 34,046
Basic Earnings Per Share:				
Income Before Accounting Change	$ 0.71	$ 0.31	$ 1.98	$ 1.07
Cumulative Effect of Adoption of Accounting Principle	-	-	-	(0.03)
Net Income	$ 0.71	$ 0.31	$ 1.98	$ 1.04
Diluted Earnings Per Share:				
Income Before Accounting Change	$ 0.68	$ 0.30	$ 1.92	$ 1.04
Cumulative Effect of Adoption of Accounting Principle	-	-	-	(0.03)
Net Income	$ 0.68	$ 0.30	$ 1.92	$ 1.01
Weighted Average Common Shares Outstanding:				
Basic	35,772,641	35,090,330	35,664,911	32,786,030
Diluted	37,090,111	36,028,157	36,843,718	33,582,506

The accompanying notes are an integral part of the financial statements

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	September 30, 2004	December 31, 2003
	(in thousands)	
Current Assets		
Cash	$ 1,234	$ 1,277
Accounts receivable	46,959	58,543
Inventories, at average cost	34,646	31,418
Under-recovered purchased gas costs	3,881	1,107
Hedging asset - FAS No. 133	4,042	3,693
Deferred income tax assets	11,900	-
Other	3,755	4,272
Total current assets	106,417	100,310
Investments	12,740	13,840
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,413,040	1,201,917
Gas distribution systems	206,559	203,793
Gas in underground storage	32,254	33,256
Other	33,507	30,038
	1,685,360	1,469,004
Less: Accumulated depreciation, depletion and amortization	757,110	706,720
	928,250	762,284
Other Assets	15,219	14,276
Total Assets	$ 1,062,626	$ 890,710

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	September 30, 2004	December 31, 2003
	(in thousands)	
Current Liabilities		
Accounts payable	$ 73,611	$ 54,186
Taxes payable	5,146	5,692
Interest payable	6,209	2,338
Customer deposits	5,504	5,277
Hedging liability - FAS No. 133	43,594	20,997
Regulatory liability - hedges	3,066	2,137
Other	3,087	4,441
Total current liabilities	140,217	95,068
Long-Term Debt	295,500	278,800
Other Liabilities		
Deferred income tax liabilities	186,841	147,295
Other	30,475	15,859
	217,316	163,154
Commitments and Contingencies		
Minority Interest in Partnership	12,367	12,127
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 37,225,584 shares	3,723	3,723
Additional paid-in capital	125,495	123,519
Retained earnings	317,546	246,885
Accumulated other comprehensive income (loss)	(34,433)	(12,520)
Less: Common stock in treasury, at cost, 984,336 shares at September 30, 2004 and 1,307,995 shares at December 31, 2003	(10,962)	(14,571)
Unamortized cost of 415,831 restricted shares at September 30, 2004 and 421,617 restricted shares at December 31, 2003 issued under stock incentive plans	(4,143)	(5,475)
	397,226	341,561
Total Liabilities and Shareholders' Equity	$ 1,062,626	$ 890,710

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the nine months ended September 30,	
	2004	2003
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 70,661	$ 34,046
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	55,343	43,130
Deferred income taxes	41,499	21,391
Ineffectiveness of cash flow hedges	2,303	(779)
Gain on sale of other property, plant & equipment	(5,802)	(2,991)
Equity in (income) loss of NOARK partnership	1,100	(1,026)
Minority interest in partnership	241	342
Cumulative effect of adoption of accounting principle	-	855
Change in operating assets and liabilities:		
Accounts receivable	11,585	2,176
Inventories	(5,034)	(5,072)
Under-recovered purchased gas costs	(2,774)	(7,773)
Accounts payable	11,742	6,459
Interest payable	3,871	3,726
Other operating assets and liabilities	(1,416)	367
Net cash provided by operating activities	183,319	94,851
Cash Flows From Investing Activities		
Capital expenditures	(211,371)	(121,723)
Distribution from NOARK partnership	-	2,500
Proceeds from sale of other property, plant & equipment	7,121	3,649
Increase in gas stored underground	-	(5,423)
Other items	11	499
Net cash used in investing activities	(204,239)	(120,498)
Cash Flows From Financing Activities		
Issuance of common stock	-	103,085
Payments on revolving long-term debt	(312,600)	(229,700)
Borrowings under revolving long-term debt	329,300	149,300
Debt issuance costs	(1,514)	-
Change in bank drafts outstanding	1,504	1,056
Proceeds from exercise of common stock options	4,187	1,586
Net cash provided by financing activities	20,877	25,327
Increase (decrease) in cash	(43)	(320)
Cash at beginning of year	1,277	1,690
Cash at end of period	$ 1,234	$ 1,370

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Common Stock		Additional Paid-In	Retained	Accumulated Other Comprehensive	Common Stock in	Unamortized Restricted Stock	
	Shares	Amount	Capital	Earnings	Income (Loss)	Treasury	Awards	Total
				(in thousands)				
Balance at December 31, 2003	37,226	$ 3,723	$ 123,519	$ 246,885	$ (12,520)	$ (14,571)	$ (5,475)	$ 341,561
Comprehensive income:								
Net income	-	-	-	70,661	-	-	-	70,661
Change in value of derivatives	-	-	-	-	(21,913)	-	-	(21,913)
Total comprehensive income	-	-	-	-	-	-	-	48,748
Exercise of stock options	-	-	1,893	-	-	3,577	-	5,470
Issuance of restricted stock	-	-	83	-	-	32	(115)	-
Amortization of restricted stock	-	-	-	-	-	-	1,447	1,447
Balance at September 30, 2004	37,226	$ 3,723	$ 125,495	$ 317,546	$ (34,433)	$ (10,962)	$ (4,143)	$ 397,226

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
	(in thousands)		(in thousands)	
Balance, beginning of period	$ (24,201)	$ (26,299)	$ (12,520)	$ (17,358)
Current period reclassification to earnings	5,259	4,080	12,900	21,043
Current period change in derivative instruments	(15,491)	8,997	(34,813)	(16,907)
Balance, end of period	$ (34,433)	$ (13,222)	$ (34,433)	$ (13,222)

The accompanying notes are an integral part of the financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
September 30, 2004

(1) BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such information reflects all adjustments (consisting solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. The Company's significant accounting policies are summarized in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003 (the "2003 Annual Report on Form 10-K").

(2) ISSUANCE OF COMMON STOCK

In the first quarter of 2003, the Company completed the sale of 9,487,500 shares of its common stock under a registration statement filed with the Securities and Exchange Commission in December 2002. Aggregate net proceeds from the equity offering of $103.1 million were used to pay outstanding borrowings under the Company's revolving credit facility. The Company is reborrowing the repaid amounts under the credit facility as necessary to fund the acceleration of the development of the Company's Overton Field in East Texas and for general corporate purposes.

(3) GAS AND OIL PROPERTIES

The Company follows the full cost method of accounting for the exploration, development and acquisition of gas and oil reserves. Under this method, all costs (productive and nonproductive) directly attributable to these activities, including salaries, benefits and other internal costs, are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company's unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At September 30, 2004, our unamortized costs of gas and oil properties did not exceed this ceiling amount. Our standardized measure at September 30, 2004 was calculated based upon quoted market prices of $6.40 per Mcf for Henry Hub gas and $49.64 per barrel for West Texas Intermediate oil, adjusted for market differentials. A decline in gas and oil prices from September 30, 2004 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

The Company's adoption of Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (FAS 143), in January 2003 impacted its accounting for gas and oil properties principally by (1) recognizing future asset retirement obligations as a cost of its oil and gas properties and (2) subjecting to depreciation, depletion and amortization the recorded asset retirement costs as well as estimated future retirement costs associated with future development activities on proved properties, net of salvage value associated with the retirement of the properties. The new standard did not have a material impact upon the Company's calculation of its ceiling test. Additionally, the impact of adoption of FAS 143 did not have a material effect on the Company's financial position or results of operations.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142), were issued in June 2001 and became effective for the Company on July 1, 2001, and January 1, 2002, respectively. The Company previously reported that an interpretation of FAS 141 and 142 was being considered as to whether mineral interest use rights in gas and oil properties are intangible assets and would be classified as such, separate from gas and oil properties. In September 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. 142-2; which clarified that the classification and disclosure provisions of FAS 142 are not applicable to drilling and mineral rights of oil and gas producing entities. Therefore, the Company is not required to reclassify or disclose information regarding its oil and gas mineral interests in accordance with FAS 141 and FAS 142.

(4) EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each period. The diluted earnings per share calculation adds the incremental shares underlying outstanding unexercised dilutive stock options and unvested restricted shares to the weighted average number of common shares outstanding. Options for 4,000 shares, with an average exercise price of $39.74 per share at September 30, 2004 were not included in the calculation of diluted shares because they would have had an antidilutive effect. Options for 2,212,767 shares at September 30, 2004, with a weighted average exercise price of $10.59, and options for 2,546,127 shares at September 30, 2003, with a weighted average exercise price of $10.20, were included in the calculation of diluted shares. Restricted shares included in the calculation of diluted shares were 208,603 and 495,416 at September 30, 2004 and 2003, respectively.

(5) DEBT

Debt balances as of September 30, 2004 and December 31, 2003 consisted of the following:

	September 30, 2004	December 31, 2003
	(in thousands)	
Senior notes:		
6.70% Series due December 2005	$ 125,000	$ 125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	225,000
Other:		
Variable rate (3.04% at September 30, 2004 and 2.67% at December 31, 2003) unsecured revolving credit arrangements	70,500	53,800
Total debt	$ 295,500	$ 278,800

In January 2004, the Company entered into a $300 million three-year unsecured revolving credit facility that replaced its previous $125 million credit facility which was scheduled to expire in July 2004. The Company also entered into a separate $15 million three-year unsecured credit facility at the same time. The interest rate on each of the credit facilities is calculated based upon our debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). Any downgrades in our public debt ratings could increase the cost of funds under our revolving credit facilities. The credit facilities contain covenants which impose certain restrictions on the Company. Under the credit agreements, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. The Company was in compliance with the covenants of its debt agreements at September 30, 2004.

(6) DERIVATIVE AND HEDGING ACTIVITIES

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, was adopted by the Company on January 1, 2001. FAS 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement.

At September 30, 2004, the Company's net liability related to its cash flow hedges was $53.6 million. Additionally, at September 30, 2004, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of $33.9 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. The amount estimated to be reclassified to pre-tax earnings as a loss over the next 12 months is approximately $42.6 million. The change in accumulated other comprehensive income (loss) related to derivatives was a loss of $16.2 million ($10.2 million after tax) and a gain of $21.1 million ($13.1 million after tax) for the three months ended September 30, 2004 and 2003, respectively, and a loss of $34.8 million ($21.9 million after tax) and a gain of $6.7 million ($4.1 million after tax) for the nine months ended September 30, 2004 and 2003, respectively. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the application of FAS 133.

(7) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131 "Disclosures about Segments of an Enterprise and Related Information." The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gas distribution segment arise from the transportation and sale of natural gas at retail. The marketing segment generates revenue through the marketing of both Company and third-party produced gas volumes.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 to the financial statements in the Company's 2003 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes and the cumulative effect of adoption of accounting principle is the sum of operating income, interest expense, other income (expense) and minority interest in partnership. The "Other" column includes items not related to the Company's reportable segments including real estate, pipeline operations and corporate items.

	Exploration And Production	Gas Distribution	Marketing	Other	Total
			(in thousands)		
Three months ended September 30, 2004:					
Revenues from external customers	$70,993	$18,146	$17,989	$4,267 (1)	$111,395 (1)
Intersegment revenues	4,677	24	67,061	112	71,874
Operating income (loss)	43,113	(2,690)	712	4,302	45,437
Depreciation, depletion and amortization expense	18,304	1,624	9	23	19,960
Interest expense (2)	2,834	1,063	106	209	4,212
Provision (benefit) for income taxes (2)	14,766	(1,387)	224	1,314	14,917
Assets	838,802	162,391	21,126	40,307 (3)	1,062,626 (3)
Capital expenditures	87,721 (4)	2,026	-	1,143	90,890 (4)

Three months ended September 30, 2003:					
Revenues from external customers	$41,913	$16,050	$10,114	$ 2,991 (1)	$71,068 (1)
Intersegment revenues	4,964	19	45,425	112	50,520
Operating income (loss)	22,295	(3,420)	799	3,033	22,707
Depreciation, depletion and amortization expense	13,307	1,554	12	23	14,896
Interest expense (2)	2,760	1,198	11	248	4,217
Provision (benefit) for income taxes (2)	7,228	(1,760)	299	900	6,667
Assets	631,111	155,708	15,472	36,161 (3)	838,452 (3)
Capital expenditures	45,898 (4)	1,731	1	180	47,810 (4)
Nine months ended September 30, 2004:					
Revenues from external customers	$176,627	$102,335	$42,849	$5,801 (1)	$327,612 (1)
Intersegment revenues	23,986	106	175,896	336	200,324
Operating income	113,994	4,692	2,410	5,894	126,990
Depreciation, depletion and amortization expense	47,640	4,840	27	70	52,577
Interest expense (2)	8,273	3,338	246	687	12,544
Provision for income taxes (2)	38,679	497	801	1,522	41,499
Assets	838,802	162,391	21,126	40,307 (3)	1,062,626 (3)
Capital expenditures	210,732 (4)	5,207	1	1,789	217,729 (4)
Nine months ended September 30, 2003:					
Revenues from external customers	$104,733	$94,099	$34,387	$ 2,991 (1)	$236,210 (1)
Intersegment revenues	25,369	114	118,969	336	144,788
Operating income	62,708	2,477	2,026	3,116	70,327
Depreciation, depletion and amortization expense	36,238	4,622	36	69	40,965
Interest expense (2)	9,032	3,271	13	759	13,075
Provision (benefit) for income taxes (2)	19,689	(351)	765	1,288	21,391
Assets	631,111	155,708	15,472	36,161 (3)	838,452 (3)
Capital expenditures	121,130 (4)	6,671	3	474	128,278 (4)

(1) Other revenues from external customers in 2004 and 2003 resulted from the sale of undeveloped real estate and certain fixed assets.
(2) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense are incurred at the corporate level.
(3) Other assets include the Company's equity investment in the operations of the NOARK Pipeline System, Limited Partnership, corporate assets not allocated to segments, and assets for non-reportable segments.
(4) Exploration and Production capital expenditures include $3.8 million and $6.4 million for the three and nine month periods ended September 30, 2004, respectively, and $6.6 million for the three and nine month periods ended September 30, 2003 relating to the effects of accrued expenditures.

Intersegment sales by the exploration and production segment and marketing segment to the gas distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, debt issuance costs and intangible pension related costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(8) INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented. Interest payments in 2003 include amounts paid for the settlement of interest rate hedges.

	For the nine months ended September 30,	
	2004	2003
	(in thousands)	
Interest payments	$ 9,339	$ 9,292
Income tax payments	$ -	$ -

(9) MINORITY INTEREST IN PARTNERSHIP

In 2001, the Company's subsidiary, Southwestern Energy Production Company (SEPCO) formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. Because SEPCO is the sole general partner and owns a majority interest in the partnership, the operating and financial results are consolidated with the Company's exploration and production results and the investor's share of the partnership activity is reported as minority interest in the financial statements.

(10) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. At September 30, 2004 and December 31, 2003, the outstanding principal for these notes was $68.0 million and $69.0 million, respectively. The Company's share of the several guarantee is 60%. The notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. Under the several guarantee, the Company is required to fund its share of NOARK's debt service to the extent not funded by operations of the pipeline. Additionally, the Company's gas distribution subsidiary has a transportation contract for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system under which approximately $4.2 million in costs have been incurred by our gas distribution subsidiary in 2004. This contract expires in 2014.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to litigation and claims that arise in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

(11) ACCOUNTING FOR STOCK-BASED COMPENSATION

The Company's stock-based employee compensation plan is accounted for under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost related to stock options is reflected in net income as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company does record compensation cost for the amortization of restricted stock shares issued to employees. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
	(in thousands, except per share)			
Net Income, as reported	$ 25,399	$ 10,878	$ 70,661	$ 34,046
Add back: Amortization of restricted stock	302	436	912	1,303
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(563)	(718)	(1,755)	(2,149)
Pro forma net income	$ 25,138	$ 10,596	$ 69,818	$ 33,200
Earnings per share:				
Basic-as reported	$ 0.71	$ 0.31	$ 1.98	$ 1.04
Basic-pro forma	0.70	0.30	1.96	1.01
Diluted-as reported	0.68	0.30	1.92	1.01
Diluted-pro forma	0.68	0.29	1.89	0.99

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions for all periods presented: no dividend yield; expected volatility of 48.7%; risk-free interest rate of 3.7%; and expected lives of 6 years for all option grants. There were 11,000 options granted in the first nine months of 2004 and no options granted in the first nine months of 2003.

(12) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three- and nine-month periods ended September 30, 2004 and 2003:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
	(in thousands)			
Service cost	$ 601	$ 543	$ 1,803	$ 1,629
Interest cost	923	915	2,769	2,745
Expected return on plan assets	(1,136)	(902)	(3,408)	(2,706)
Amortization of prior service cost	111	112	333	334
Amortization of net loss	58	166	175	498
Net periodic benefit cost	$ 557	$ 834	$ 1,672	$ 2,500

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
	(in thousands)			
Service cost	$ 44	$ 35	$ 131	$ 105
Interest cost	63	60	189	179
Expected return on plan assets	(10)	(9)	(31)	(27)
Amortization of net loss	25	22	76	66
Amortization of transition obligation	22	22	65	65
Net periodic benefit cost	$ 144	$ 130	$ 430	$ 388

We currently expect to contribute $1.9 million to our pension plan in 2004, which is down from our original estimate at the end of 2003 of $2.4 million. As of September 30, 2004, $1.4 million of contributions have been made.

(13) NEW PRONOUNCEMENTS

In September 2004, the staff of the Securities and Exchange Commission issued Staff Accounting Bulletin No. 106 (SAB 106) to express the staff's views regarding application of FAS 143, "Accounting for Asset Retirement Obligations," by oil and gas producing companies following the full cost accounting method. SAB 106 addressed the computation of the full cost ceiling test to avoid double-counting asset retirement costs, the disclosures a full cost accounting company is expected to make regarding the impacts of FAS 143, and the amortization of estimated dismantlement and abandonment costs that are expected to result from future development activities. The accounting and disclosures described in SAB 106 have been adopted by the Company as of the third quarter of 2004 and did not have a material impact on the financial position of the Company, or on its results of operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following updates information as to Southwestern Energy Company's financial condition provided in our 2003 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2004, and the comparable periods of 2003. For definitions of commonly used gas and oil terms as used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2003 Annual Report on Form 10-K.

OVERVIEW

Southwestern Energy Company is an integrated energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We also operate integrated natural gas distribution systems in northern Arkansas. As a complement to our other businesses, we provide marketing and transportation services in our core areas of operation. We operate our business in three segments: Exploration and Production, Natural Gas Distribution and Natural Gas Marketing.

Our financial results depend on a number of factors, including in particular natural gas and oil prices, our ability to find and produce natural gas and oil, our ability to control costs, the seasonality of our customers' need for natural gas and our ability to market natural gas and oil on economically attractive terms to our customers, all of which are dependent upon numerous factors beyond our control such as economic, political and regulatory developments and competition from other energy sources. There has been significant price volatility in the natural gas and crude oil market in recent years. The volatility was attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we cannot control or predict.

Our business strategy is focused on providing long-term growth in the net asset value of our business. We prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value created for each dollar invested, which we refer to as PVI. The present value of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax present value for each dollar we invest in our Exploration and Production, or E&P, business. We are also focused on creating and capturing additional value beyond the wellhead through our natural gas distribution, marketing and transportation businesses.

Quarter Ended September 30, 2004 Compared with Quarter Ended September 30, 2003

We reported net income of $25.4 million, or $0.68 per share on a diluted basis, on revenues of $111.4 million for the three months ended September 30, 2004, up from $10.9 million, or $0.30 per diluted share, on revenues of $71.1 million for the same period in 2003. Included in our results for the third quarter of 2004 was a pre-tax gain of $4.3 million, or approximately $0.07 per diluted share, on the sale of undeveloped real estate. In the third quarter of 2003, the company recorded a pre-tax gain of $3.0 million, or $0.05 per diluted share, for the sale of real estate and certain fixed assets. Operating income for our E&P segment was $43.1 million for the quarter ended September 30, 2004, up from $22.3 million for the same period in 2003. The increases in our net income and in the operating income for the E&P segment were primarily due to a 36% increase in production volumes and higher realized natural gas and oil prices, which were partially offset by an increase in our operating costs and expenses. Our gas distribution segment incurred a seasonal operating loss of $2.7 million for the three months ended September 30, 2004, compared to a loss of $3.4 million for the same period in 2003. The decrease in operating loss for our gas distribution segment resulted primarily from an increase in approved rates charged to customers that was implemented in October 2003.

In the third quarter of 2004, our gas and oil production continued to increase, reaching 15.0 Bcfe, up from 11.1 Bcfe in the third quarter of 2003 and 12.6 Bcfe in the second quarter of 2004. The increase in 2004 production primarily resulted from an increase in production from our Overton Field in East Texas due to the accelerated development of the field, increased production in the Arkoma basin and production from our River Ridge discovery in New Mexico.

Our capital investments totaled $90.9 million for the third quarter of 2004, up from $47.8 million in the third quarter of 2003. We invested $87.7 million in our E&P segment in the third quarter of 2004, compared to $45.9 million for the same period in 2003.

Nine Months Ended September 30, 2004 Compared with Nine Months Ended September 30, 2003

Net income for the nine months ended September 30, 2004 was $70.7 million, or $1.92 per share on a diluted basis, on revenues of $327.6 million, compared to net income of $34.0 million, or $1.01 per diluted share, on revenues of $236.2 million for the same period in 2003. Operating income for our E&P segment was $114.0 million for the first nine months of 2004, up from $62.7 million for the same period in 2003. The increases in our net income and in the operating income for the E&P segment were primarily due to a 30% increase in production volumes and higher prices realized for our production, partially offset by increased operating costs and expenses. Operating income for our gas distribution segment was $4.7 million for the first nine months of 2004, compared to $2.5 million for the same period in 2003. The increase in operating income for our gas distribution segment resulted primarily from increased rates implemented in October 2003. Our cash flow from operating activities was $183.3 million for the nine months ended September 30, 2004, compared to $94.9 million for the same period in 2003. The increase in operating cash flow was primarily due to the improved financial results of our E&P segment.

In the first nine months of 2004, our gas and oil production increased to 39.0 Bcfe, up from 30.0 Bcfe in the same period of 2003. The increase in 2004 production primarily resulted from an increase in production from our Overton Field in East Texas due to the accelerated development of the field, increased production in the Arkoma basin and production from our River Ridge discovery in New Mexico.

Our capital investments totaled $217.7 million for the first nine months of 2004, up from $128.3 million in the first nine months of 2003. We invested $210.7 million in our E&P segment in the first nine months of 2004, compared to $121.1 million for the same period in 2003. Capital investments currently planned for calendar year 2004 total $284.7 million, including $275.2 million for our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
Revenues (in thousands)	$75,670	$46,877	$200,613	$130,102
Operating income (in thousands)	$43,113	$22,295	$113,994	$62,708
Gas production (MMcf)	13,996	10,241	36,293	27,601
Oil production (MBbls)	164	136	456	400
Total production (MMcfe)	14,980	11,053	39,029	29,999
Average gas price per Mcf, including hedges	$5.04	$4.23	$5.07	$4.22
Average gas price per Mcf, excluding hedges	$5.49	$4.84	$5.55	$5.40
Average oil price per Bbl, including hedges	$31.21	$26.46	$29.51	$27.17
Average oil price per Bbl, excluding hedges	$42.78	$28.77	$38.07	$29.81
Average unit costs per Mcfe				
Lease operating expenses	$0.38	$0.43	$0.38	$0.40
General & administrative expenses	$0.33	$0.37	$0.35	$0.40
Taxes, other than income taxes	$0.24	$0.22	$0.26	$0.24
Full cost pool amortization	$1.19	$1.17	$1.19	$1.17

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 61% to $75.7 million for the three months ended September 30, 2004 and up 54% to $200.6 million for the nine months ended September 30, 2004, as compared to the respective periods in 2003. The increases were primarily due to increased production volumes and higher gas and oil prices realized for our production.

Operating Income. Operating income for the E&P segment was up 93% to $43.1 million for the third quarter of 2004 and up 82% to $114.0 million for the nine months ended September 30, 2004, compared to $22.3 million and $62.7 million for the same respective periods in 2003. The increase in operating income resulted from the increase in revenues, partially offset by increased operating costs and expenses.

Production. Gas and oil production during the third quarter of 2004 was 15.0 billion cubic feet (Bcf) equivalent, up 36% from 11.1 Bcf equivalent in the third quarter of 2003. Gas and oil production was 39.0 Bcf equivalent for the first nine months of 2004, compared to 30.0 Bcf equivalent for the same period of 2003. The comparative increases in production primarily resulted from an increase in production from our Overton Field in East Texas due to the accelerated development of the field, increased production in the Arkoma basin and production from our River Ridge discovery in New Mexico. Gas production was 14.0 Bcf for the third quarter of 2004 up from 10.2 Bcf for the third quarter of 2003. Gas production was 36.3 Bcf for the first nine months of 2004 compared to 27.6 Bcf for the same period of 2003. Intersegment sales to our gas distribution systems were 4.2 Bcf during the nine months ended September 30, 2004, compared to 4.4 Bcf for the same period in 2003. Our oil production was 164 thousand barrels (MBbls) during the third quarter of 2004 and 456 MBbls for the first nine months of 2004, up from 136 MBbls and 400 MBbls for the same periods of 2003, respectively.

Commodity Prices

The average price realized for our gas production, including the effect of hedges, was $5.04 per thousand cubic feet (Mcf) for the three months ended September 30, 2004, up from $4.23 per Mcf for the same period of 2003. For the first nine months of 2004, we received an average gas price of $5.07 compared to $4.22 for the same period of 2003. The changes in the average price realized primarily reflect changes in average spot market prices and the effects of our price hedging activities. Our hedging activities lowered our average gas price realized during the first nine months of 2004 by $0.48 per Mcf, compared to $1.18 per Mcf during the same period of 2003. Additionally, we have historically received demand charges related to sales made to our utility segment, which have increased the average gas price realized.

We periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. For the remainder of 2004, we have hedges in place for 10.7 Bcf of gas production and for 2005 and 2006 we have 45.0 Bcf and 27.0 Bcf, respectively, of our future gas production hedged. See Part I, Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

We realized an average price of $29.51 per barrel for our oil production, including the effect of hedges, during the nine months ended September 30, 2004, up from $27.17 per barrel for the same period of 2003. The average price we received for our oil production in the first nine months of 2004 and 2003 was reduced by $8.56 per barrel and $2.64 per barrel, respectively, due to the effects of our hedging activities. For the remainder of 2004, we have hedged 102,000 barrels of our oil production at an average NYMEX price of $27.92 per barrel. For 2005 and 2006, we have hedged 360,000 barrels and 120,000 barrels, respectively, of our future oil production.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.38 for both the third quarter and the first nine months of 2004, compared to $0.43 and $0.40 for the same respective periods in 2003. The decreases in lease operating expenses per Mcfe in 2004 resulted from the increase in our production volumes. Taxes other than income taxes per Mcfe were $0.24 and $0.26 for the third quarter and first nine months of 2004, respectively, compared to $0.22 and $0.24 for the same periods in 2003. The increases in severance taxes per Mcfe in 2004 are primarily due to comparatively higher average market prices in effect for natural gas and crude oil, as reflected in the average price received for our production excluding the effect of hedges. General and administrative expenses per Mcfe were $0.33 and $0.35 during the third quarter and for the first nine months of 2004, down from $0.37 and $0.40 for the same periods in 2003. The decreases in per unit general and administrative expenses in 2004 are primarily due to the increases in our production volumes. General and administrative expenses for our E&P segment increased to $4.9 million and $13.8 million for the third quarter and first nine months of 2004, respectively, compared to $4.1 million and $12.0 million for the same periods of 2003 due primarily to increased compensation costs. Our full cost pool amortization rate was $1.19 per Mcfe for the third quarter and the first nine months of 2004, compared to $1.17 per Mcfe for the same periods in 2003. The increase in our full cost pool amortization rate was primarily due to increased finding and development costs. Depreciation, depletion and amortization expense for our E&P segment increased to $18.3 million and $47.6 million for the third quarter and first nine months of 2004, respectively, compared to $13.3 million and $36.2 million for the same periods of 2003 primarily as a result of the increase in production volumes.

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. We exclude all costs of unevaluated properties from immediate amortization. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At September 30, 2004, our unamortized costs of gas and oil properties did not exceed this ceiling amount. Our standardized measure at September 30, 2004 was calculated based upon quoted market prices of $6.40 per Mcf for Henry Hub gas and $49.64 per barrel for West Texas Intermediate oil, adjusted for market differentials. A decline in gas and oil prices from the September 30, 2004 levels, as well as changes in production rates, levels of reserves and the evaluation of costs excluded from amortization, could cause a future write-down of capitalized costs and a non-cash charge against future earnings. We refer you to “Critical Accounting Policies—Natural Gas and Oil Properties” below for additional information.

Natural Gas Distribution

	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
Revenues (in thousands)	$18,170	$16,069	$102,441	$94,213
Gas purchases (in thousands)	$9,188	$8,448	$63,529	$58,082
Operating costs and expenses (in thousands)	$11,672	$11,041	$34,220	$33,654
Operating income (loss) (in thousands)	($2,690)	($3,420)	$4,692	$2,477
Deliveries (Bcf)				
Sales and end-use transportation	3.2	3.1	16.8	17.6
Off-system transportation	-	-	1.0	0.1
Customers at period-end	139,631	137,001	139,631	137,001
Average sales rate per Mcf	$12.18	$11.00	$9.18	$7. 77
Heating weather - degree days	18	43	2,340	2,597
Percent of normal	43%	102%	94%	104%

Revenues and Operating Income

Revenues. Gas distribution revenues fluctuate due to the pass-through of gas supply cost changes and the effects of weather. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected net income. Revenues for the three- and nine-month periods ended September 30, 2004 increased 13% and 9%, respectively, from the comparable periods of 2003 due primarily to increased cost of gas supplies caused by higher gas prices and to the effects of a $4.1 million annual rate increase implemented in October 2003.

Operating Income. The seasonal operating loss for our gas distribution segment decreased $0.7 million in the third quarter of 2004 and operating income increased $2.2 million in the first nine months of 2004, as compared to the same periods of 2003. The changes in operating income were primarily due to the rate increase implemented in late 2003. The increase in operating income for the first nine months of 2004 was partially offset by decreased volumes sold due to warmer than normal weather. Weather during the first nine months of 2004 was 6% warmer than normal and 10% warmer than the same period in 2003. While our utility segment’s results have improved since last year, we do not believe it is currently earning its authorized rate of return. As a result, and as discussed below in “Regulatory Matters,” we have filed a notice of intent to file for a rate increase request with the Arkansas Public Service Commission (APSC) before the end of the year.

Deliveries and Rates

The utility systems delivered 3.2 Bcf and 16.8 Bcf to sales and end-use transportation customers during the three- and nine-month periods ended September 30, 2004, compared to 3.1 Bcf and 17.6 Bcf for the same periods in 2003. The decrease in deliveries during the first nine months of 2004 was primarily due to the effects of warmer weather and customer conservation brought about by high gas prices. Our utility's tariffs contain a weather normalization clause intended to lessen the impacts of revenue increases and decreases that might result from weather variations during the winter heating season. The increase in gas costs in the first nine months of 2004 was reflected in the utility segment's average rate for its sales which increased to $9.18 per Mcf, up from $7.77 per Mcf for the same period in 2003. The fluctuations in the average sales rate reflect changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses. Our utility segment hedged 3.8 Bcf of gas purchases in the first nine months of 2004 which had the effect of decreasing its total gas supply cost by $0.1 million. In the first nine months of 2003, our utility hedged 2.7 Bcf of its gas supply which decreased its total gas supply cost by $7.5 million. At September 30, 2004, we have 2.4 Bcf of future gas purchases hedged at an average purchase price of $6.31 per Mcf. See Part I, Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses

The changes in purchased gas costs for our gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Other operating costs and expenses for this segment during the third quarter were higher than the comparable period of the prior year due primarily to higher general and administrative expenses. The increase in general and administrative expense primarily resulted from increased compensation costs.

Regulatory Matters

On October 1, 2004, our utility subsidiary filed with the APSC a notice of its intention to file for a modification in its rates and charges. The Public Service Commission requires utilities to notify the APSC not less than 60 days nor more than 90 days prior to the filing of the application. Although the amount of a requested increase has not yet been determined, our preliminary analysis indicates that current revenues are not sufficient to cover the cost of providing utility service and earn the rate of return authorized by the APSC. The APSC has ten months from the date the application is filed to render its decision. Any rate increase allowed would likely be implemented in the fourth quarter of 2005.

Marketing and Transportation

Marketing

	For the three months ended September 30,		For the nine months ended September 30,	
	2004	2003	2004	2003
Revenues (in thousands)	$85,050	$55,539	$218,745	$153,356
Operating income (in thousands)	$712	$799	$2,410	$2,026
Gas volumes marketed (Bcf)	15.9	12.2	41.3	30.9

Our operating income from natural gas marketing was $0.7 million on revenues of $85.0 million in the third quarter of 2004, and $2.4 million on revenues of $218.7 million for the first nine months of 2004, compared to $0.8 million on revenues of $55.5 million and $2.0 million on revenues of

$153.4 million in the same respective periods of 2003. The increases in revenues from natural gas marketing are largely attributable to increased volumes marketed and higher purchased gas costs. Operating income from natural gas marketing fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity. The increase in revenues for the three- and nine-month periods ended September 30, 2004, as compared to the same periods in the prior year, was primarily due to an increase in affiliated volumes marketed. These increases in revenues were largely offset by comparable increases in purchased gas costs. We marketed 12.5 Bcf of affiliated gas in the third quarter of 2004, representing 79% of total volumes marketed, compared to 9.3 Bcf, or 76% of total volumes marketed, for the same period in 2003. Affiliated gas marketed for the first nine months of 2004 was 32.6 Bcf compared to 22.6 Bcf for the same period in 2003. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Qualitative and Quantitative Disclosure about Market Risks" in this Form 10-Q for additional information.

Transportation

We recorded a pre-tax loss from operations related to our investment in the NOARK Pipeline System Limited Partnership (NOARK) of $0.6 million for the third quarter of 2004 and $1.1 million for the first nine months of 2004, compared to a pre-tax loss of $0.4 million for the third quarter of 2003 and pre-tax income of $1.0 million for first nine months of 2003. These amounts were recorded in other income (expense) in our income statement. The pre-tax loss in the first nine months of 2004 included adjustments to previous allocations of income and expense by the pipeline's operator. Our share of the pre-tax income in the first nine months of 2003 included a gain of $1.3 million from NOARK's sale of a 28-mile portion of its pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million.

Other Revenues

Revenues and operating income for the first nine months of 2004 and 2003 include pre-tax gains of $3.0 million and $2.6 million, respectively, related to the sale of gas in storage inventory. Additionally, the third quarter and first nine months of 2004 included gains of $4.3 million and $5.8 million, respectively, related to sales of undeveloped real estate. Revenues and operating income for the third quarter and first nine months of 2003 included a gain of $3.0 million related to the sales of undeveloped real estate and certain fixed assets.

Interest Expense

Interest costs, net of capitalization, were approximately the same for the third quarters of 2004 and 2003, and decreased 4% for the first nine months of 2004, compared to the same periods in 2003. During the third quarter of 2004, higher interest costs that resulted from increased average borrowings were offset by an increase in capitalized interest. Interest costs decreased for the nine months ended September 30, 2004, as compared to the same period in 2003, primarily due to increased capitalized interest. Changes in capitalized interest are primarily due to the level of costs excluded from amortization in our E&P segment.

Income Taxes

Our effective tax rate for the nine months ended September 30, 2004 was 37.0% compared to 38.0% for the same period in 2003. The changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We recorded pension expense of $0.6 million in the third quarter of 2004 and $1.7 million for the first nine months of 2004 compared to pension expense of $0.8 million and $2.5 million, respectively, for the same periods in 2003. The amount of pension expense recorded by us is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $1.9 million to our pension plan in 2004, which is down from our original estimate at the end of 2003 of $2.4 million. As of September 30, 2004, $1.4 million of contributions have been made. For further information regarding our pension plans, we refer you to Note 12 of the financial statements in this Form 10-Q and "Critical Accounting Policies" below.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our unsecured revolving credit facilities (discussed below under "Financing Requirements") as our primary sources of liquidity. We may borrow up to $315.0 million under our revolving credit facilities from time to time. As of September 30, 2004, we had $70.5 million of indebtedness outstanding under our revolving credit facilities. During 2004, we expect to draw on a portion of the funds available under our credit facilities to fund our planned capital expenditures (discussed below under "Capital Expenditures"). In December 2002, we filed a shelf registration statement with the SEC pursuant to which we may from time to time, subject to market conditions, publicly offer equity, debt or other securities.

Net cash provided by operating activities was $183.3 million in the first nine months of 2004, compared to $94.9 million for the same period of 2003. The primary components of cash provided from operations are net income adjusted for depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. For the first nine months of 2004, cash provided by operating activities provided 87% of our requirements for capital expenditures. For the same period of 2003, cash provided by operating activities supplied 78% these requirements.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 6 to the financial statements included in this Form 10-Q and Item 3, "Quantitative and Qualitative Disclosures about Market Risks." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Our capital expenditures for the first nine months of 2004 were $217.7 million, including $6.4 million relating to the effects of accrued expenditures, compared to $128.3 million for the same period in 2003 including $6.6 million relating to the effects of accrued expenditures. We currently expect our capital investments for calendar year 2004 to be approximately $284.7 million, including $275.2 million of capital investments in our E&P segment. Our 2004 capital investment program is expected to be funded through cash flow from operations and, as necessary, borrowings under our revolving credit facilities. We may adjust our level of future capital investments dependent upon the level of cash flow generated from operations.

Off-Balance Sheet Arrangements

We hold a 25% general partnership interest in NOARK, which owns the Ozark Pipeline that is utilized to transport our gas production and the gas production of others. We account for our investment under the equity method of accounting. We and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. This debt financed a portion of the original cost to construct the NOARK Pipeline. Our share of the guarantee is 60% and we are allocated 60% of the interest expense. At September 30, 2004, the outstanding principal amount of these notes was $68.0 million and our share of the guarantee was $40.8 million. The notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. Under the several guarantee, we are required to fund our share of NOARK's debt service which is not funded by operations of the pipeline. We were not required to advance any funds to NOARK in the first nine months of 2004. We do not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income (expense) related to our NOARK investment was a pre-tax loss of $0.6 million for the third quarter of 2004 and $1.1 million for the first nine months of 2004, compared to a pre-tax loss of $0.4 million for the third quarter of 2003 and pre-tax income of $1.0 million for the first nine months of 2003. The pre-tax loss in the first nine months of 2004 included adjustments to previous allocations of income and expense by the pipeline’s operator. Our share of the pre-tax income in the nine months of 2003 included a gain of $1.3 million from NOARK's sale of a 28-mile portion of its pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million. We believe that we will be able to continue to improve the operating results of the NOARK project and expect our investment in NOARK to be realized over the life of the system.

Contractual Obligations and Contingent Liabilities and Commitments

We enter various contractual obligations in the normal course of our operations and financing activities. Our significant contractual obligations at September 30, 2004 are as follows:

Contractual Obligations

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
			(in thousands)		
Long-term debt	$295,500	$ -	$195,500	$ -	$100,000
Operating leases(1)	5,476	1,280	1,697	955	1,544
Unconditional purchase obligations(2)	-	-	-	-	-
Demand charges(3)	105,587	11,570	19,320	19,832	54,865
Other obligations(4)	3,173	3,058	90	25	-
	$409,736	$15,908	$216,607	$20,812	$156,409

(1) We lease certain office space and equipment under non-cancelable operating leases expiring through 2013.

(2) Our utility segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at September 30, 2004 totaled 2.2 Bcf, comprised of 1.5 Bcf in less than one year, 0.5 Bcf in one to three years, 0.1 Bcf in three to five years and 0.1 Bcf in more than five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(3) Our utility segment has commitments for approximately $100.2 million of demand charges on firm non-cancelable gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has a commitment for approximately $5.4 million of demand transportation charges.

(4) Our significant other contractual obligations include approximately $1.0 million for funding of benefit plans, approximately $1.0 million of various information technology support and data subscription agreements, $0.5 million for drilling rig commitments, and approximately $0.4 million of land leases.

We refer you to "Financing Requirements" below for a discussion of the terms of our long-term debt.

Contingent Liabilities or Commitments

We have the following commitments and contingencies that could create, increase or accelerate our liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, we expect to record pension expense of approximately $2.2 million in 2004, $1.7 million of which has been recorded in the first nine months of 2004. For further information regarding our pension plans, we refer you to Note 12 of the financial statements in this Form 10-Q and "Critical Accounting Policies" below.

As discussed above in "Off-Balance Sheet Arrangements," we have guaranteed 60% of the principal and interest payments on NOARK's 7.15% Notes due 2018. At September 30, 2004 the outstanding principal of these notes was $68.0 million and our share of the guarantee was $40.8 million. The notes require semi-annual principal payments of $1.0 million.

Financing Requirements

Our total debt outstanding was $295.5 million at September 30, 2004 and $278.8 million at December 31, 2003. Of the total outstanding at September 30, 2004, $70.5 million was outstanding under our revolving credit facilities. In January 2004, we entered a new $300 million three-year unsecured revolving credit facility that replaced our previous $125 million credit facility which was scheduled to expire in July 2004. We also entered into a separate $15 million three-year unsecured credit facility at the same time. The interest rate on each of the new facilities is calculated based upon our debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). Our publicly traded notes are rated BBB by Standard and Poor's and Ba2 by Moody's. Any downgrades in our public debt ratings could increase the cost of funds under our revolving credit facilities.

Our revolving credit facilities contain covenants which impose certain restrictions on us. Under the credit agreements, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. EBITDA is a measure required by our debt covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Additionally, there are also restrictions on the ability of our subsidiaries to incur debt. We were in compliance with the covenants of our debt agreements at September 30, 2004. Although we do not anticipate that we will violate any debt covenant, our ability to comply with our debt agreements is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil.

At September 30, 2004, our capital structure consisted of 43% debt (excluding our several guarantee of NOARK's obligations), down from 45% at December 31, 2003, and our ratio of EBITDA to interest expense was 13.2. At September 30, 2004, the NOARK partnership had outstanding debt totaling $68.0 million. We and the other general partner of NOARK have severally guaranteed the principal and interest payments on the NOARK debt. Our share of the several guarantee is 60%.

Working Capital

We maintain access to funds that may be needed to meet seasonal requirements through our above-described credit facilities. We had negative working capital of $33.8 million at September 30, 2004, compared to positive working capital of $5.2 million at December 31, 2003. At September 30, 2004, we had an aggregate of $244.5 million of available borrowing capacity under our revolving credit facilities. Our current assets increased by 6% in the first nine months of 2004 while current liabilities increased 47%. The increase in current assets during the first nine months of 2004 was due primarily to a $11.9 million increase in deferred income tax assets related to the current hedging liability combined with a $3.2 million increase in current inventories. These increases were partially offset by a $11.6 million decrease in accounts receivable caused primarily by the seasonality of the gas distribution segment's operations. The change in current liabilities was primarily caused by a $23.5 million increase in our hedging liabilities, and a $19.4 million increase in accounts payable related to our increased level of capital expenditures. Under-recovered purchased gas costs for the Company's gas distribution segment were $3.9 million at September 30, 2004, compared to $1.1 million at December 31, 2003. Purchased gas costs are recovered from our utility customers in subsequent months through automatic cost of gas adjustment clauses included in the utility's filed rate tariffs. Changes in other current assets, accounts payable and other current liabilities are primarily due to the timing of expenditures and receipts.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. Under these rules, all such costs (productive and nonproductive) directly attributable to these activities, including salaries, benefits and other internal costs, are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on September 30, 2004, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We engage the services of an independent petroleum consulting firm to audit reserves as estimated by our reservoir engineers.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142), were issued in June 2001 and became effective for the Company on July 1, 2001, and January 1, 2002, respectively. The Company previously reported that an interpretation of FAS 141 and 142 was being considered as to whether mineral interest use rights in gas and oil properties are intangible assets and would be classified as such, separate from gas and oil properties. In September 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. 142-2;

which clarified that the classification and disclosure provisions of FAS 142 are not applicable to drilling and mineral rights of oil and gas producing entities. Therefore, we are not required to reclassify or disclose information regarding our oil and gas mineral interests in accordance with FAS 141 and FAS 142.

Hedging

We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow, as well as to manage the price volatility of natural gas purchases in our gas distribution segment, due to fluctuations in the prices of natural gas and oil and in interest rates. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged.

Our derivative instruments are accounted for under FAS 133 and are recorded at fair value in our financial statements. We utilize market-based quotes from our hedge counterparties to value these open positions. These valuations are recognized as assets or liabilities in our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, gas marketing transactions or interest rates, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected on the income statement in natural gas and oil sales or in gas purchases. Results of settled interest rate hedges are reflected on the income statement in interest expense. Ineffective hedges, derivatives not qualifying for accounting treatment as hedges, or ineffective portions of hedges are recognized immediately in earnings. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in this Form 10-Q for additional information regarding our hedging activities.

Regulated Utility Operations

Our utility operations are subject to the rate regulation and accounting requirements of the APSC. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from those generally applied by non-regulated operations. Such allocations to meet regulatory accounting requirements are considered generally accepted accounting principles for regulated utilities provided that there is a demonstrated ability to recover any deferred costs in future rates.

During the ratemaking process, the regulatory commission may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. This causes certain expenses to be deferred as a regulatory asset and amortized to expense as they are recovered through rates. The regulatory commission has not required any unbundling of services, although some business customers are free to contract for their own gas supply. There are no regulations relating to unbundling of services currently anticipated; however, should any such regulation be proposed and adopted, certain of these assets may no longer meet the criteria for deferred recognition and, accordingly, a write-off of regulatory assets and stranded costs could be required.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation. Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For 2003, the assumed discount rate was 6.75% for the periodic benefit cost and 6.25% for the benefit obligations. The assumed expected return was 9.0% for 2003.

For 2004, we expect our pension expense to be approximately $2.2 million using an assumed discount rate of 6.25% and an assumed expected return of 9.0%. Pension expense of $1.7 million was recorded in the first nine months of 2004.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 9.3 Bcf at $3.43 at September 30, 2004 and 10.4 Bcf at $3.33 at December 31, 2003.

The gas in inventory for the E&P segment is used primarily to supplement field production in meeting the segment's contractual commitments including delivery to customers of our gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the gas distribution segment to the E&P segment, which are passed through to the utility's customers, are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. Declines in the future market price of natural gas could result in a write down of our gas in storage carrying cost.

See further discussion of our significant accounting policies in Note 1 to the financial statements in our 2003 Annual Report on Form 10-K.

FORWARD-LOOKING INFORMATION

All statements, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in forward-looking statements. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in commodity prices for natural gas and oil;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the extent to which the Fayetteville Shale play can replicate the results of other productive shale gas plays;
- the potential for significant variability in reservoir characteristics of the Fayetteville Shale over such a large acreage position;
- our future property acquisition or divestiture activities;
- the effects of weather and regulation on our gas distribution segment;
- increased competition;
- the impact of federal, state and local government regulation;
- the financial impact of accounting regulations and critical accounting policies;
- changing market conditions and prices (including regional basis differentials);
- the comparative cost of alternative fuels;
- conditions in capital markets and changes in interest rates;
- the availability of oil field personnel, services, drilling rigs and other equipment; and

- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks set forth under the heading “Risk Factors” in Part I, Item 1 of our 2003 Annual Report on Form 10-K which are incorporated by reference herein.

Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described or incorporated by reference above occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 4% of accounts receivable at September 30, 2004. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

Revolving debt obligations are sensitive to changes in interest rates. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate, although we do not have any interest rate swaps in effect currently.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our marketing segment, and to hedge the purchase of gas in our utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for our gas and oil production, gas purchases and marketing activities. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the fair value by expected maturity dates. At September 30, 2004, the fair value of these financial instruments was a $53.6 million liability.

	Expected Maturity Date		
	2004	2005	2006
<u>Production and Marketing</u>			
Natural Gas			
Swaps with a fixed price receipt			
Contract Volume (Bcf)	3.8	12.9	5.0
Weighted average price per Mcf	$5.75	$5.10	$5.89
Fair value (in millions)	($4.6)	($20.2)	($1.5)
Price collars			
Contract volume (Bcf)	6.9	32.4	22.0
Weighted average floor price per Mcf	$4.01	$4.67	$4.64
Fair value of floor (in millions)	-	$1.6	$4.2
Weighted average ceiling price per Mcf	$6.70	$8.00	$8.69
Fair value of ceiling (in millions)	($6.0)	($17.8)	($6.3)
Swaps with a fixed price payment			
Contract volume (Bcf)	0.1	0.2	-
Weighted average price per Mcf	$5.88	$6.04	-
Fair value (in millions)	$0.1	$0.3	-
Oil			
Swaps with a fixed price receipt			
Contract volume (MBbls)	102	360	120
Weighted average price per Bbl	$27.92	$33.17	$37.30
Fair value (in millions)	($2.1)	($4.1)	($0.3)
<u>Natural Gas Purchases</u>			
Swaps with a fixed price payment			
Contract volume (Bcf)	0.8	1.6	-
Weighted average price per Mcf	$6.32	$6.30	-
Fair Value (in millions)	$0.7	$2.4	-

At September 30, 2004, the Company had outstanding fixed-price basis differential swaps on 0.6

Bcf of 2004 and 0.5 Bcf of 2005 gas production that did not qualify for hedge accounting treatment. The fair value of these differential swaps was an asset of $0.1 million at September 30, 2004.

At December 31, 2003, the Company had outstanding natural gas price swaps on total notional volumes of 8.0 Bcf at a weighted average price per Mcf of $4.21 in 2004 and 6.0 Bcf at a weighted average price per Mcf of $4.67 in 2005. Outstanding oil price swaps on 426 MBbls were in place that are yielding the Company an average price of $28.39 per barrel during 2004. At December 31, 2003, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 3.8 Bcf in 2004 for which the Company paid an average fixed price of $5.34 per Mcf.

At December 31, 2003, the Company had collars in place on 23.6 Bcf in 2004 and 1.0 Bcf in 2005 of gas production. The 23.6 Bcf in 2004 has a weighted average floor and ceiling price of $3.85 and $6.48 per Mcf, respectively. The 1.0 Bcf in 2005 has a weighted average floor and ceiling price of $4.50 and $8.00 per Mcf, respectively.

Subsequent to September 30, 2004 and prior to October 26, 2004, we entered into additional derivative contracts to hedge gas production sales. During this time period we added a costless collar hedge on 1.0 Bcf of 2005 gas production sales that has an average floor of $5.00 per Mcf and an average ceiling of $18.00 per Mcf.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and our Chief Financial Officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Our disclosure controls and procedures are the controls and other procedures that we designed to ensure that we record, process, summarize, and report in a timely manner the information we must disclose in reports that we file with the SEC. Our disclosure controls and procedures include our internal accounting controls. Based on the evaluation of our Chief Executive Officer and our Chief Financial Officer, our disclosure controls and procedures are effective. There were no changes in our internal controls or in other factors that could materially affect these controls subsequent to the date of our evaluation.

PART II

OTHER INFORMATION

Items 1 - 5.

No developments required to be reported under Items 1 - 5 occurred during the quarter ended September 30, 2004.

Item 6(a). Exhibits

(31.1) Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2) Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32.1) Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Item 6. Exhibits.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: October 28, 2004

/s/ GREG D. KERLEY
Greg D. Kerley
Executive Vice President
and Chief Financial Officer